BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-182-E - ORDER NO. 2021-569

AUGUST 19, 2021

IN RE: South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators (See Docket No. 2020-229-E)	)	ORDER DETERMINING THE COSTS AND BENEFITS OF NET ENERGY METERING PROGRAMS AND THE VALUE OF CUSTOMER GENERATION

I. INTRODUCTION

Continuing the Commission's implementation of the South Carolina Energy Freedom Act ("Act 62") (enacted by General Assembly in H.3659 (2019)), this Order adopts a new analytical framework to evaluate customer-generator programs, including the existing net energy metering ("NEM") program and future Act 62 solar choice metering programs. The purpose of this generic docket is to "investigate and determine the costs and benefits of the current net energy metering program" and to "establish a methodology for calculating the value of the energy produced by customer-generators." S.C. Code Ann. § 58-40-20(C).

The Commission intends the analytical framework to be flexible, evolving over time to adjust to circumstances, innovation, and technological advances. Under Act 62, the Commission is required to evaluate the costs and benefits of the existing NEM program using an enumerated list of factors. S.C. Code Ann. § 58-40-20(F)(2). Specifically, the

Commission must consider:

(1) the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation, distribution, and transmission;

(2) the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study;

(3) the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194;

(4) the direct and indirect economic impact of the net energy metering program to the State; and

(5) any other information the commission deems relevant.

S.C. Code Ann. § 58-40-20(D).

A. Background of Net Energy Metering in South Carolina

This Commission first considered net metering in response to an Office of Regulatory Staff ("ORS") petition for the Commission to consider implementing various voluntary provisions of Section 1251 of the Energy Policy Act of 2005 ("EPAct"). The Commission opted to adopt net metering on a limited basis through Order No. 2007-618 issued August 30, 2007, which required South Carolina Electric & Gas Company ("SCE&G") (now Dominion Energy South Carolina, Inc. or "DESC"), Carolina Power & Light Company (now Duke Energy Progress, LLC or "DEP"), and Duke Energy Carolinas, LLC ("DEC") to file net metering tariffs. Order No. 2008-416 issued June 24, 2008, required a review of the net metering programs in approximately twelve months so the Commission could consider whether any changes were warranted at that time.

In Order No. 2009-552 issued August 6, 2009, the Commission undertook a review of the experimental net metering tariffs adopted in compliance with federal EPAct of the various electrical utilities and approved a settlement that, among other things: (1) standardized the structure of the NEM program for statewide uniformity; (2) allowed a full retail credit (one-to-one kWh offset) under the flat rate for excess energy credits (as opposed to a mandatory time-of-use rate with a demand component); (3) eliminated standby charges; (4) allowed "renewable energy generators" to retain the rights to Renewable Energy Credits ("RECs"), except for those associated with net excess generation; and (5) provided for review of the program in four years.

In 2014, the General Assembly codified the NEM program by adding a new Chapter 40 to Title 58 as part of the South Carolina Distributed Energy Resource Act, S.1189 ("Act 236"). Act 236 capped participation in NEM at "two percent of the previous five-year average of the electrical utility's South Carolina retail peak demand" (S.C. Code Ann. § 58-40-20(B) (2014)) and only came into legal operation if a utility had an approved Distributed Energy Resource ("DER") Program.[1]

The Commission then approved a settlement in Order No. 2015-194 ("NEM Settlement") establishing the Act 236 NEM program, which included a procedure for annually calculating the value of DERs (the "NEM Methodology") and for collecting the so-called NEM DER Incentive, which was calculated by subtracting the value of DER from the full retail rate that was offset by each kWh of generation for customer-generators.

[1] The DEP program was approved by Order 2015-514 (July 15, 2015); DEC's program was approved by Order No. 2015-515 (July 15, 2015); and SCE&G program was approved by Order No. 2015-512 (July 15, 2015).

Under the NEM Methodology, the total value of DERs is determined by summing eleven different cost and benefit components; Order No. 2015-194 defines and provides a calculation methodology for each of those components (NEM Methodology table included as Order Exhibit No. 1). The NEM Settlement, among other things, also established that full retail net energy metering (i.e., the one-to-one kWh crediting rate) would be offered on a first-come basis through the NEM Settlement effective period (i.e., until January 1, 2021) or until statutory limits on program participation under Act 236 were reached. The NEM Settlement provided that customer-generators applying and receiving service pursuant to the NEM Settlement "shall have the right to remain on that rate, according to the terms and conditions specified in this Settlement Agreement through December 31, 2025." (Order No. 2015-194, Order Exhibit 1, page 6.)

On May 16, 2019, Governor McMaster signed the South Carolina Energy Freedom Act ("Act 62"). Act 62 modified much of Chapter 40 (Net Energy Metering), Title 58 — first established by Act 236. Act 62 extends the terms and conditions of the Act 236 NEM Settlement (approved by Order No. 2015-194) for customer-generators that apply for NEM service after the effective date of Act 62 and before June 1, 2021 ("Interim Customer-Generators"). S.C. Code § 58-40-20(I) (Supp. 2020). Act 62 requires the Commission to "(1) investigate and determine the costs and benefits of the current net energy metering program and (2) establish a methodology for calculating the value of the energy produced by customer-generators." S.C. Code Ann. § 58-40-20(C)(1) (Supp. 2020).

B. Commission Jurisdiction and Authority Over Net Energy Metering and Customer-Generator Programs

Net energy metering is a retail practice that involves billing a customer for their net electrical consumption. Section 58-40-10(E) defines "net energy metering" as involving "the difference between the electrical energy supplied to a customer-generator by an electrical utility and the electrical energy supplied by the customer-generator to the electricity provider over the applicable billing period." The Commission establishes the schedule of rates, fees, credits, and charges for the applicable rate to which the NEM billing practice applies, and Act 236 defined the "applicable billing period" over which these exports and imports of electricity are netted. Under the Act 236 form of NEM, these one-to-one retail NEM credits were applied across the annual billing period as set by statute, with any excess remaining at the end of the annual billing period compensated to the customer-generator at the electrical utility's avoided cost.[2]

The payment for excess credits at the end of the billing period, on the other hand, involves the payment or crediting of those excess kWh credits at the utility's avoided cost, a wholesale rate. Ordinarily, the Federal Energy Regulatory Commission ("FERC") has exclusive jurisdiction over "the sale of electric energy at wholesale in interstate commerce," (16 U.S.C. § 824(b)(1)) with the exception of the establishment of wholesale rates for purchases by utilities from Qualifying Facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). 16 U.S.C. § 824a-3 *et seq.*

Accordingly, the Commission's jurisdiction over NEM is rooted in the exclusive jurisdiction that states retain over retail rates but is subject to the constraints of PURPA in establishing an avoided cost rate for any net excess generation that remains at the end of

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[2] Prior Section 58-40-20(D)(4) provided that "Annually, the utility shall pay the customer-generator for any accrued net excess generation at the utility's avoided cost for qualified facilities, zeroing-out the customer-generator's account of net excess kWh credits." Section 58-40-20(D)(4) (2014).

the applicable billing period. The Commission's duties in determining the applicable billing period is grounded in the exercise of its retail jurisdiction. The analytical framework should provide information that is appropriate to inform the exercise of this jurisdiction and discretion, distinct from the Commission's obligations and constraints under federal law when establishing wholesale rates for QFs under the limited authority delegated to state regulatory authorities by PURPA.

The Commission acknowledges that it establishes a rate of compensation for net excess generation that remains at the end of the billing period or defined "energy measurement interval" pursuant to PURPA. The analytical framework adopted in this Order is appropriate for evaluating the NEM program and future customer-generator programs under our jurisdiction over retail rates and retail practices. This analytical framework is not intended to be precedential or to replace the existing methodologies approved for calculating the avoided cost paid by electrical utilities to QFs. Because the practice of netting does not involve the "sale" of electricity, the Commission evaluates customer-generator programs like NEM or successor solar choice metering according to standards appropriate to other retail programs, including energy efficiency and demand-side management. The Commission must engage in a balancing of interests using its retail jurisdiction, which requires it to consider a range of long-run forward looking values.

II. NOTICE AND INTERVENTION

This docket was opened on May 28, 2019 pursuant to Act 62's directive that the Commission determine the costs and benefits of the existing metering program and update the valuation of customer-generator produced electricity. The utilities required to appear for review of programs included Duke Energy Carolinas, LLC ("DEC"), Duke Energy

Progress, LLC ("DEP"), and Dominion Energy South Carolina, Incorporated, ("DESC").

Alder Energy Systems, LLC ("Alder Energy Systems"), North Carolina Sustainable Energy Association ("NCSEA"), Nucor Steel – South Carolina ("Nucor Steel"), the South Carolina Appleseed Legal Justice Center ("Justice Center"), Solar Energy Industries Association ("SEIA"), South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Upstate Forever, and Vote Solar intervened. The South Carolina Office of Regulatory Staff ("ORS") is automatically a party pursuant to S.C. Code Ann. § 58-4-10(B). In accordance with South Carolina Code Section 37-6-604(C), the South Carolina Department of Consumer Affairs ("SCDCA") was provided notice of this matter and related filings; however, SCDCA did not intervene. S.C. Code Ann. § 37-6-604 (Supp. 2020).

III. HEARING

The Commission convened a virtual hearing on this matter on November 17, 2020 and concluding November 19, 2020, with the Honorable Justin T. Williams, Chairman, presiding on November 17, 2020, and the Honorable Florence P. Belser, Vice Chairman, presiding on November 18 – 19, 2020.

DESC was represented by Matthew W. Gissendanner, Esquire. DEC and DEP were represented by Heather Shirley Smith, Esquire, and J. Ashley Cooper, Esquire. The Justice Center was represented by Adam Protheroe, Esquire. Nucor Steel was represented by Robert R. Smith, II, Esquire. Vote Solar was represented by Thadeus B. Culley, Esquire, and Bess J. DuRant, Esquire. NCSEA was represented by Jeffrey W. Kuykendall, Esquire, and Peter Ledford, Esquire. SEIA was represented by Jeffrey W. Kuykendall, Esquire. CCL, SACE, and Upstate Forever were represented by Kate Lee Mixson, Esquire. Alder

Energy Systems was represented by R. Taylor Speer, Esquire. ORS was represented by Jeffrey M. Nelson, Esquire, and Jenny R. Pittman, Esquire.

In this Order, DESC, DEC and DEP, Justice Center, Nucor Steel, Vote Solar, NCSEA, SEIA, CCL, SACE, Upstate Forever, and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

DESC presented the direct and responsive testimony of Mark C. Furtick, direct testimony of Scott Robinson, and direct and responsive testimony of Margot Everett. DEC and DEP presented the direct testimony of George V. Brown and Leigh C. Ford and the direct and rebuttal testimony of Julius A. Wright, Ph.D., Bradley Harris, and Lon Huber. Vote Solar, CCL, SACE, Upstate Forever, SEIA, and NCSEA presented the direct and rebuttal testimony of R. Thomas Beach. SEIA and NCSEA presented the direct and rebuttal testimony of Justin R. Barnes. CCL, SACE, Upstate Forever, and Vote Solar presented the direct testimony of Frank L. Hefner, Ph.D. Vote Solar presented the direct and responsive testimony of Odette Mucha. Alder Energy Systems presented the direct and rebuttal testimony of Donald R. Zimmerman. ORS presented the direct testimony of Robert A. Lawyer, John C. Ruoff, Ph.D., and Brian K. Horii. The Justice Center and Nucor Steel did not present witnesses at the hearing.

IV. FINDINGS OF FACT

Based on the testimony and exhibits received into evidence at the hearing and the entire record of the proceedings, the Commission hereby makes the following findings of fact:

Analytical Framework for Evaluating Customer-Generator Programs Aggregate Marginal Benefits and Costs

1. The requirement of Act 62 to examine long-run benefits and costs of customer-generators in the aggregate to the utility's transmission, distribution, and generation components makes it appropriate to consider a range of values over the expected life of the typical customer-generator system within the analytical framework for analyzing the current NEM program.

2. Marginal costs are the change in the costs of providing electrical service due to a change in demand, which are typically thought of as changes to variable costs. The Act 62 requirement to look at "long-run" marginal costs means that the Commission should consider not just changes in variable costs, but also changes in "fixed" factors such as generation, transmission, and distribution assets because in the long-run these costs are also affected by customer-generator production.

3. By their nature, long-run projections have uncertainty and reflect the risk of over- or underestimating a particular value over a long horizon for which there is currently imperfect information. Considering a range of methodologically sound future estimates of long-run benefits and costs allows the Commission to utilize its discretion to give appropriate weight to this range of outcomes in its ultimate determination under the analytical framework.

4. The record supports a finding of twenty-year expected useful life for solar photovoltaic ("PV") systems. Solar PV may remain productive beyond that time, though total production will decline due to panel degradation.

5. All self-generation that is consumed by a customer-generator within the

billing period is, from the system perspective, equivalent to energy efficiency or demand-side management measures as a decrement to system load.

Cost of Service Analysis

6. The cost of service analysis required by Act 62 can provide evidence of the existence or extent of cross-subsidization between customer-generators and non-customer-generators in the same class within the snapshot of a single test year, but it is not wholly conclusive. The cost of service analyses will be helpful in fine-tuning solar choice metering rates and design in future proceedings but will not itself be determinative.

7. Performing the Act 62 cost of service analysis requires consideration of a hypothetical circumstance, in which customer-generators within a class are separated out as a separate class for analytical purposes. This cost of service analysis aids the Commission in determining: (1) the cost to serve those customer-generators and (2) the relative rate of return received by the electrical utility in providing service to that theoretical class of customers.

8. Act 62 does not require the Commission to create a separate class of service for customer-generators and there is no reason to do so at this time.

9. Performing both embedded and marginal cost of service studies gives the Commission additional information to consider the impact of customer-generators on both historic and future utility costs.

10. Evaluating the theoretical customer-generator classes under the cost of service analytical factor requires load data, or a method consistent with an electrical utility's current load research, on a statistically significant sample of customer-generators. Where this is not currently possible, it is reasonable to estimate the hourly usage profile of

a customer-generator using historic usage profiles and estimating the net hourly usage profile of these customers by applying the aggregate generation profile for that corresponding period recorded from all customer-generators with production meters owned and controlled by the electrical utility. The load of customer-generators should be evaluated within the cost of service analysis on the basis of net hourly consumption from the electric grid.

11. For purposes of the customer-generator cost of service study, a customer that is a net exporter of electricity during an hour should be recorded as having zero, rather than negative, consumption during the hour. This approach should also be followed to determine the aggregate hourly net load profile of all customer-generators within a class of service.

12. The use of the same Commission approved cost of service allocators including methods of allocating costs to the theoretical customer generator classes on which effective rates are based at the time of evaluation, as well as the use of a test year that is more recent than the test year relied upon in the utility's most recent rate case is reasonable. Requests to use allocators and test years differing from the most recent Commission approved rates must be supported by substantial justification.

Value of Distributed Energy Resources Methodology

13. The existing cost-benefit categories for evaluation approved by Order No. 2015-194 are appropriate for determining the value of customer generation, subject to the requirement that all categories be populated with a value or that a proponent give a sufficient explanation for why it is not practical to determine a value for a particular category at that time.

14. While the categories of value of DERs approved in Order No. 2015-194 continue to be appropriate and well-accepted, updates to the methodology used to calculate values are required to be consistent with the Act 62 analytical framework and its requirement to include consideration of long-run marginal costs and benefits. To the extent this Order amends the calculation methodologies for the existing cost-benefit categories approved by Order No. 2015-194, it is appropriate to require utilities use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code Ann. § 58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery.

DER Value: Avoided Energy

15. There are temporal and seasonal variations in energy costs for electrical utilities that are not currently reflected in the legacy valuation framework for DER.

DER Value: Avoided Capacity

16. Avoided capacity costs in the value of DER should reflect the twenty year expected life span of solar PV.

DER Value: Ancillary Services

17. Customer-generators do not currently provide ancillary services for compensation from electrical utilities. As commercially available technology expands the feasibility of customer DERs providing ancillary services and technical standards throughout the industry emerge, electrical utilities must investigate how they could create programs to leverage DER to provide ancillary services to populate this value category.

DER Value: Avoided Carbon Dioxide Emissions

18. If state or federal laws impose regulatory burdens on electric utilities going

forward, then it is reasonable to require electric utilities to provide the Commission with the quantifiable costs of complying with those regulations that limit carbon dioxide and methane emissions so that customer-generators can be credited with an appropriate benefit in meeting those emission standards.

DER Value: Avoided Fuel Hedge

19. If the electrical utility engaged in financial hedging activities to hedge against rising fuel costs, then it is reasonable to require the electric utility to keep sufficient data to determine the prudency of those costs.

DER Value: Avoided Transmission and Distribution Capacity

20. While not all utilities possess the granularity of data required to provide high-confidence quantification of avoided transmission and distribution value, there are techniques accepted across the utility industry for recognizing the avoided transmission and distribution values of DER. It is appropriate to require such a technique or method to quantify the long-term impacts of the aggregate customer-generator fleet on avoided transmission and distribution costs.

DER Value: Avoided Line Losses

21. The best practice is to calculate avoided line losses on a marginal basis considering only daylight hours (when solar PV produces).

DER Value: Utility Integration and Interconnection Costs

22. Utility integration costs are determined in the avoided cost proceeding, but should only be applied to exported power since behind the meter consumption is viewed the same as energy. Integration costs for customer-sited DER should focus more on any distribution-system related impacts.

23. It is appropriate to require electrical utilities to begin to track the incremental interconnection costs associated with customer-generator interconnections that are not currently covered by the interconnection application fee to determine any negative or positive impact on revenue.

Economic Impacts of the Net Metering Program

24. Act 62 requires the Commission to consider the direct and indirect economic impacts of NEM on the state.

25. The economic impacts of the net energy program are difficult to quantify and calculate, but may be used qualitatively in the Commission's consideration of the impact of NEM and successor programs on our state after further study.

26. For purposes of further study, Witness Wright's analysis is appropriate for use in determination of direct and indirect economic impacts in future NEM proceedings.

Cost-Effectiveness Tests

27. The Commission finds that it is appropriate to evaluate a breadth of cost-benefit measurement, metrics, and calculation methods in order to consider all of the relevant information that all the parties may wish to present in the record of this and future cases.

V. REVIEW OF EVIDENCE AND EVIDENTIARY CONCLUSIONS

A. Aggregate Impact of Customer-Generators on Long-Run Marginal Costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1 THROUGH 5

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

Witness Beach, the joint witness of NCSEA, SEIA, Vote Solar, CCL, and SACE ("Joint Witness Beach"), testified that the challenge with determining the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation, distribution, and transmission is "calculating long-run marginal costs for certain DER values over the full life of DER resources." (Tr. p. 290.15, lines 6-9) Witness Beach stated that the expected life of solar PV is typically between 25 to 30 years and that such time frame is appropriate for determining long-run values. (Tr. p. 290.21, lines 1-3) Witness Beach testified that typically solar panels do come with a manufacturer's warranty covering the useful life of the solar panels. (Tr. p. 316, line 3 – Tr. p. 317, line 12) Witness Beach's rebuttal asserted that DESC Witness Everett's direct testimony did not analyze the costs and benefits of distributed solar resources over the full economic life of those systems. (Tr. p. 294.5, lines 14-17)

DESC Witness Robinson testified that his analysis of payback period of the current NEM program assumed a "financial life of 20 years, with 0.5% annual degradation." (Tr. p. 93.7, lines 18-20) DESC Witness Furtick noted during cross examination that he performed sensitivity analyses for up to 30 years. (Tr. p.112, lines 6-9) NCSEA and SEIA

Witness Barnes gave a range of expected useful life for solar PV of between 20 to 30 years. (Tr. p. 327.35, lines 1-4)

Witness Beach stated that there are “longstanding and well-accepted” approaches to calculating long-run marginal costs within specific cost categories. (Tr. 290.22, lines 1-5). Specifically, Witness Beach asserted that many utilities use the National Economic Research Associates regression method to determine their long-run marginal disruption capacity costs. (Tr. p. 290.22, lines 2-5) Witness Beach described and applied techniques to calculate long-run avoided capacity costs for generation (Tr. p. 294.09, line 8 – 294.10, line 16), avoided transmission and distribution (Tr. p. 294.12, line 2 – Tr. p. 294.15, line 2), and fuel hedge (Tr. p. 294.15, line 4 – Tr. p. 294.17, line 11), and estimated a value for each of those categories. (Tr. p.294.18)

DEC/DEP Witness Harris testified that it is appropriate to view the long-run marginal costs of customer-generation differently based on whether the generation is consumed behind the meter or is “excess energy” exported to the grid. (Tr. p. 353.13, line 23 – Tr. p. 353.14, line 6) For behind the meter consumption, Witness Harris testified that the impact is the same as if the customer had “reduced their consumption through an energy efficiency or demand-side management program” and should be evaluated in a similar manner. *Id.* For excess energy, Witness Harris stated that it should be evaluated in the same fashion as the Companies’ avoided costs, as most recently approved in Docket Nos.2019-185-E and 2019-186-E. *Id.*

ORS Witness Horii defined marginal costs as the “change in the costs of providing electrical service due to a small change in demand.” (Tr. p. 576.9, lines 1 – 2) Witness Horii noted that marginal costs are different than average costs, which reflect the costs of the output of all plants. (Tr. p. 576.9, lines 4 – 5) Witness Horii suggested that the modifier "long-run" before marginal costs in statute "indicates that marginal cost should not just reflect changes in variable costs, but also consider changes in 'fixed' factors such as generation, transmission, and distribution assets." (Tr. p. 576.9, lines 14 – 16)

Commission Conclusions

Act 62 establishes a new set of mandatory analytical tools to evaluate customer-generator programs which adds to and modifies existing methodology. With Order No. 2015-194, the Commission approved a stipulated methodology for determining the value of DERs—or more precisely, the value of solar PV—and the record shows that the categories used to calculate these values remain largely accepted. This methodology has been used to establish the wholesale value of all generation from customer-generators in order to calculate the DER NEM Incentive, a cost recovery mechanism approved by Order No. 2015-194 as part of the compromise and settlement adopting the Act 236 full retail (one-to-one) NEM rate.

Accordingly, it is appropriate to continue use of the valuation categories approved in Order No. 2015-194, with some modifications in this Order to calculation methodologies and new standards to populate particular value categories. Any category or method that the Commission does not address or modify in this Order remains unchanged.

The first major task the legislature put before the Commission was to expand the view of the existing DER valuation method to incorporate long-term costs and benefits from DERs. The Commission is required to consider "the aggregate impact of customer-generators on the electrical utility's long-run marginal cost of generation, distribution, and transmission…." S.C. Code Ann. § 58-40-20(D)(1). There is no real controversy among parties over the definition of marginal costs as incremental changes in variable costs due to a small change in demand. The Act 62 analytical framework for valuation of customer-generation requires that the Commission takes an appropriate long-run view of the benefits and costs of these customer-generators to an electrical utility's grid. Over the long-run, even costs the Commission has traditionally considered as "fixed" (*e.g.*, generation, distribution, andtransmission) become – in a sense - variable.

As it concerns the length of time over which the analytical framework will view these costs and benefits, the Commission is mindful of the tensions identified by parties that the more distant in time the benefit or cost, the more uncertain the estimate. The Commission is persuaded, however, that it is appropriate to consider the cost-effectiveness of the asset at question as we would any other asset of the electrical utility; that is over the expected useful life of the asset. The Commission is mindful of the uncertainty embedded in future projections and will give appropriate weight based on the reliability and credibility of evidence putting forward future projects on the relevant analytical factors.

The record in this proceeding has revealed that a twenty-year useful life for solar PV is appropriate. Evidence in the record reveals that it is standard for analyses of solar PV to consider 20-year and 30-year useful lives. The Commission finds it is reasonable to adopt the conservative of these approaches and to utilize a 20-year expected useful or financial life for solar PV.

Additionally, as several witnesses observed, it is standard practice for the Commission to consider the cost-effectiveness of demand-side management and energy efficiency investments over the useful lives of those assets or programs. The Commission agrees with witnesses Beach and Harris that solar energy that is consumed by a customer over the course of a billing period to offset purchases from the utility looks like a reduction/decrement to load akin to energy efficiency, when viewed at a system perspective. Given that the analytical task at hand is to consider the cost-effectiveness of customer-generator programs over the expected useful life of the systems, the Commission adopts a 20-year horizon for considering these valuation categories and notes the distinction between customer-generator electricity that offsets retail kWh purchases from the electrical utility and those excess deliveries to the grid—as determined at the end of the billing period—which are treated as wholesale sales and compensated according to PURPA.

There is a difference between using this method to make a cost-effectiveness determination of a retail program, such as NEM, and the establishment of a wholesale rate under PURPA. The Commission acknowledges that PURPA grants states substantial discretion in determining the method of calculating avoided costs, but that we are constrained by federal statute and regulation in how we determine such a wholesale rate. By contrast, in evaluating state jurisdictional retail customer programs, the Commission has wide discretion to adopt a framework that reflects the requirements of Act 62 and captures the range of values that customer-generators may create.

In adopting a 20-year horizon for the analytical framework for valuing DER, the Commission notes that other elements of the framework take a more short-term look and offer information that is currently outside of the Order No. 2015-194 categories. For example, S.C. Code Ann. Section 58-40-20 (D)(2) consideration of the "cost of service implications" of customer-generators is a novel analysis in South Carolina that will take a look at customer-generators on utility revenues and costs within a single test-year. The

Commission views these approaches as complimentary tools that provide very different information and have different applications in the exercise of Commission authority over successor solar choice metering tariffs.

B. Cost of Service Implications of Customer-Generators

(1) Uses and limits of cost of service analysis of customer-generators

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 6 THROUGH 8

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

NCSEA and SEIA Witness Barnes testified that the usefulness of a cost of service study ("COSS") is relative to the overall analytical framework being used. Witness Barnes stated that a typical distributed generation ("DG") valuation method will take a long-run view of marginal benefits and costs, whereas a COSS represents a "snapshot in time of DG customer responsibility and payment for embedded costs." (Tr. p. 327.12, lines 8 – 12) While a COSS provides useful information, Barnes suggested that it does not capture what is in the interests of ratepayers in the long term. As he explained, the scope of a COSS is narrower than the scope of a typical long-run DER evaluation because the "cost of service study focuses only on the past and only on costs reflected in the utility system." (Tr. p. 327.12, lines 13 – 18) A consequence of this short-term look, Barnes suggested, is that a COSS tends to treat "some costs (*e.g.*, distribution investments) as fixed even though DG can contribute to longer-term avoidance of these types of costs." (Tr. p. 327.12, line 21 – Tr. p. 327.13, line 3)

ORS Witness Horii echoed this distinction in his testimony, stating that "[u]nlike marginal cost studies that look at *changes* in costs, [COSS] look at how to divide a utility's total accounting costs among customer classes…." (Tr. p. 576.10, lines 2 – 4)

Witness Barnes went on to explain that the benefits from DG (*i.e.*, NEM) customers in the COSS can manifest to other customers in the class in "the form of reduced allocation of costs to that class due to the presence of DG customers and how that compares to the amounts that DG customers avoid paying." (Tr. p. 327.12, lines 18 -21) DEC/DEP Witness Harris' direct testimony stated that "adding solar reduced the transmission and production costs of the Companies in excess of 75%." (Tr. p. 353.11, lines 2 – 3) At the hearing, DESC Witness Furtick was crossed on a table or graph in his rebuttal testimony that illustrated that a typical solar generation profile might reduce a customer's contribution to daily peak significantly, based on that limited single customer example. (Tr. p. 31, lines 12 – 17)

Joint Witness Beach stated that a cost of service analysis is required to justify separating customer-generators into their own rate class, as he explains that sufficient empirical evidence through a COSS would be needed to justify such distinct treatment. Witness Beach went on to state that "[i]t cannot be assumed that, after installing DER technology, customers will become significantly different than other customers in the class." (Tr. p. 290.29, lines 13 – 14) Witness Beach further stated that breaking DER customers into separate classes could proliferate and cause confusion as more DER technologies emerge (*e.g.*, solar, storage, smart thermostats, and electric heat pumps) that all have unique impacts on a customer's load profile. (Tr. p. 290.29, lines 17 – 19)

ORS Witness Horii provided direct testimony on how an embedded cost of service study that looks at customer-generators as their own class for analytical purposes can be used to determine whether a cost shift exists relative to customer-generators. Witness Horii stated that, after separating out customer-generators into a separate class (from regular non-solar customers), "the cost shift would be the difference between the costs allocated to these NEM solar and DR customers in the study compared to what those customers would pay under the otherwise applicable rate." (Tr. p. 576.12, lines 7 – 9) Witness Horii stated that an embedded COSS approach to look at customer-generators as a separate class can examine existing actual rates and the impact of proposed rates. (Tr. p. 576.16, lines 8 – 21)

Witness Harris's direct testimony provided a discussion of the cost of service analysis that he performed to analyze the existing NEM program. Witness Harris calculated the impacts of customer-generators on non-participating customers by comparing the bill reduction from solar to the cost to serve reduction from solar. (Tr. p. 165.10, lines 1 – 14) Witness Harris stated that where the bill savings exceed the cost of service reduction, NEM customers are benefitting at the expense of non-NEM customers, and where the cost of service reductions exceed bill savings, non-NEM customers are benefitting from the installation of solar. *Id.* Harris further testified that embedded COSS "also reveal whether NEM customers would provide an adequate rate of return compared to the residential rate class if they were to be a separate class within a cost of service study." (Tr. p. 353.5, lines 17 – 22)

DESC Witness Everett stated in rebuttal that "cost of service methodologies should be updated for 'costs related to use of the utility grid,' 'a customer's maximum use of the grid,' and whether the customer is serving load or exporting." (Tr. p. 131.16, lines 12 – 16)

Commission Conclusions

The Commission finds that the customer-generator cost of service analysis will provide significant insight into the existing potential for cost shift between customer-generators and non-participants, but we do not find that its results will be, standing alone, determinative of a cost shift. The analytical exercise of separating customer-generators from others in their existing classes will provide the Commission additional information about the cost to serve customer-generators and about the adequacy of future revenue recovery from those customers. This tool is particularly helpful in the ratemaking context where the rates for customer-generators can be fine-tuned to come closer to parity with the overall class—in terms of relative rate of return—but it must be used in conjunction with other analysis in making an evaluation of the benefits and costs of a customer-generator program. The cost-of-service analytical tool is an important piece of the Commission's current and future analysis of these programs, and an evaluation under the analytical framework cannot be conducted without this information in the record.

A COSS with a theoretical customer-generator class can inform, from a traditional ratemaking perspective, whether customer-generators are contributing sufficient revenue to prevent or avoid cross-subsidization within their rate class. Accordingly, this information is very useful in understanding any possible intra-class subsidization and supplements the Commission's view of the overall program under the long-run valuation methodology, but it is not sufficient to be conclusive of a cost shift. To begin with, the cost of service framework is based on a single test year. In an embedded cost perspective, it fails to address future costs and benefits and only captures those values that materialize within the cost of service study within a single year. A marginal cost of service study will tell us more about the adequacy of rates and the ability of customer-generators to avoid costs in future years, but it too provides too narrow of a window to capture the full benefits that Act 62 requires the Commission to consider for both the existing NEM program and the future consideration of solar choice metering tariffs.

This Act 62 analytical requirement does not suggest that the ultimate aim is to create a separate class of service for customer-generators. Instead, this theoretical exercise provides information regarding any potential intra-class cross subsidization that may or may not be occurring with customer-generators. The fair way to do this is to examine more closely whether customer-generators have a distinct cost to serve compared to other customers in the class and account for that difference in assessing whether rates are collecting adequate revenue from the theoretical class. While customer-generators may use the system in ways that other customers do not, as suggested by DESC Witness Everett, there is insufficient evidence in the record to conclude that customer-generators exports of power cause any additional costs to the electrical utility in safely operating the grid. As discussed below, the Commission expects electrical utilities to take prudent measures to leverage these existing customer-generator facilities to provide beneficial ancillary services.

(2) Embedded and marginal cost of service approaches

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 9

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris testified that the difference between marginal cost of service approaches and embedded ones is that a marginal cost analysis is "forward-looking" involving costs that have not yet been incurred while an embedded analysis looks at historical costs that have already been incurred. (Tr. p. 353.13, lines 15 – 18) Witness Harris stated that "marginal and embedded costs for the same service may vary due to time dependent pricing fluctuations." *Id.* Witness Harris further recommended that "[a]s required by Act 62, the Commission should consider both embedded and marginal cost of service perspectives when evaluating any cost-shifts or subsidizations in rate designs. (Tr. p. 355.3, lines 19 – 21)

ORS Witness Horii stated "[m]arginal costs are generally used when performing cost effectiveness studies or making resource decisions" while "embedded costs are generally used to determine the share of utility costs for which different customer classes should be responsible." (Tr. p. 576.14, lines 6 – 8) Witness Horii testified that both embedded and marginal cost approaches are "valid and important" for the Solar Choice Metering Tariff design discussion. (Tr. p. 576.15, lines 20 – 21) Witness Horii stated that the marginal-cost-based cost shift indicates the impact of a customer installing NEM solar at their premise and that this is the immediate impact without any rate changes and assumes the bill prior to NEM is the appropriate starting point. (Tr. p. 576.15, line 20 – Tr. p. 576.16, line 3) Horii stated that the embedded COSS does not assume that the bill before NEM is the correct starting point, but instead looks for its own starting point by modeling NEM solar customers as if they were a separate class or subclass. (Tr. p. 576.16, lines 8 – 11)

In rebuttal testimony, DESC Witness Everett testified that she agreed with Witness Horii that "care must be taken to look at forward costs," but added that the marginal cost look should be technology agnostic. (Tr. p. 131.19, lines 2 – 7) Witness Everett agreed with other witnesses that "both marginal and embedded cost methodologies are useful and provide a more complete picture in assessing future Solar Choice tariffs." (Tr. p. 131.19, lines 11 – 13)

Joint Witness Beach, in his rebuttal testimony, stated that "Act 62 clearly expects that there is a balance between the embedded and marginal cost of service perspectives that needs to be achieved in the Solar Choice tariff." (Tr. p. 294.26, lines 23 – 25)

Commission Conclusions

While Act 62 does not specify whether to require embedded or marginal cost of service studies, the Commission agrees with the majority of parties that there is benefit and unique information provided by both types of studies. Therefore, the Commission concludes examination of both embedded and marginal cost of service studies are needed to provide a complete analysis.

(3) Data requirements for cost of service analysis

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 10 & 11

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris described the data used to perform the Act 62 embedded COSS. Witness Harris stated that two primary data sets are required: (1) cost of service studies and (2) production meter data from customer-generators. Witness Harris noted that DEC/DEP's cost of service studies are the same upon which currently effective rates are based, from the rate cases in Docket Nos. 2018-318-E and 2018-319-E. (Tr. p. 353.6, lines

4 – 16) Since the COSS utilized a 2017 test year, Witness Harris noted that production meter data from customer-generators in DEC was used to establish the solar profiles in the embedded COSS for that same 2017 test year. *Id.*

Witness Harris further stated that he applied two filters to production data. First, customers with less than nine months of interval data were excluded to ensure a more reliable annual analysis. Second, customers that generated less than 50% of their overall gross load (*i.e.*, the solar offset of customer onsite load) were excluded, because those customers tend to be, in Witness Harris's words, "not representative of the Companies' expectations for future NEM customers." Witness Harris stated that it is typical for NEM customers to install solar PV systems targeting an offset of at least 85% of gross load. As Witness Harris testified, this filter only resulted in a 6% decrease in customers in the analysis. (Tr. p. 353.7, lines 4 – 14)

Witness Harris also detailed how DEC/DEP performed the cost of service study to model NEM customers as a theoretical separate class of service. After developing unit costs according to the 2018 COSS for customer costs, energy costs, distribution demand costs, transmission demand costs, and production demand costs, Witness Harris described how each unit cost was then multiplied by determinants to generate an estimated cost to serve for a representative customer both with and without rooftop solar. (Tr. p. 353.8, line 2 – Tr. p. 353.10, line 5) For an illustration of how the calculation is performed, Witness Harris stated:

> For example, to estimate energy costs, the energy unit cost would be multiplied by imports if the customer did not have solar generation. The same calculation would be done with the energy unit cost multiplied by the imports if the customer has solar generation. The estimated energy costs with and without solar can be compared to arrive at the total energy cost

> savings that are attributable to the addition of solar generation. This process was repeated for each unit cost to create a complete estimate for the costs the Companies incur for serving these customers with and without solar generation.

(Tr. p. 353.8, lines 14 – 23)

Witness Harris described how the profiles for customers with and without solar generation were derived. He stated that production meter data was put through a "SAS model" to estimate the savings a customer would realize (*i.e.,* bill reductions) from installing solar. This resulted in a bill reduction number that could be compared to the reduction in cost to serve by applying the unit costs to determinants of customers with and without rooftop solar. (Tr. p. 353.9, lines 14 – 19)

Commission Conclusions

Creating a theoretical customer class for customer-generators for purposes of the Act 62 analytical framework may require the collection of additional data that is not currently or readily available to electrical utilities. Where this is the case, the Commission requires that utilities begin to incorporate the analytical needs of Act 62 in designing load research studies that are ordinarily used to inform cost of service studies used in general rate cases. As advanced metering rollout continues, the Commission anticipates that hourly interval data (*i.e.*, 8760 load data) on the inflows and outflows from customer-generators will be available. For purposes of allocating costs, it is relevant to view the net hourly consumption of all customer-generators within a current class to develop a class load profile.

The Commission finds that electrical utilities should utilize the most recently used cost of service methodology upon which currently effective rates are based when performing this Act 62 cost of service theoretical class analysis. To perform this study, the utility shall look at the net load and demand that customer-generators within a class put on the grid. Because individual customer-generators can be net exporters in a given hour, it is reasonable to treat those customer-generators as having a load with a value of zero for the hours of excess production, or net export.

The Commission finds that it is also informative to provide information on what the revenue impact on the actual class with customer-generators would have been if not for the customer-generator systems. For this analysis, it is necessary to estimate the counterfactual of what the theoretical customer-generators' gross load would have been without behind the meter generation. For this, electrical utilities would need to have, as DEC/DEP Witness Harris described, a separate meter to record hourly production from the customer-generators and then pair this with the customer-generators recorded metered net load (*i.e.*, measured imports of exports) to determine what the gross load would have been in absence of the customer-generator. This additional counterfactual requirement will illustrate the differences in revenue requirements for all customers in a class with and without customer-generators. This is analytically distinct from the theoretical customer class analysis that looks at what revenue requirements would be if customer-generators were plucked out and placed in their own class. A counterfactual analysis will give a more complete picture as to what costs, if any, customer-generators have saved the existing class.

The Commission realizes that it could take electrical utilities some time to develop the data to produce these analyses with the same level of accuracy used in load research to support current cost of service studies. Therefore, the Commission finds it reasonable to allow electrical utilities in the interim to estimate customer-generator hourly generation profiles based on widely available tools utilizing a typical meteorological year, if actual solar generation profiles within the region and within the referenced time period (*i.e.*, test year) are not available. To estimate a customer- generator's gross load, it is reasonable to look at historic hourly usage data, where available, to reconstitute the customer's expected gross load for the counterfactual analysis described above. In some circumstances, it may be impossible for a utility to perform these analyses with imperfect or incomplete data. For such electrical utilities, the Commission orders that a load research study capable of providing a statistically significant sample of customer-generators be initiated within sixty days of this order.

(4) Cost of service methodology

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 12

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony andexhibits in this Docket and the entire record in this proceeding.

DEC/DEP Witness Harris stated that the Duke Companies thought it appropriate to utilize the cost of service studies and methodologies utilized in DEC and DEP Docket Nos. 2018-318-E and 2018-319-E, upon which existing rates are based. (Tr. p. 353.6, lines 6–11)

ORS Witness Horii stated in his direct testimony that there are three steps to performing the Act 62 cost of service analysis that have decision points: (1) determine the otherwise applicable rate that will be used as the basis of comparison; (2) determine the test year to use for the embedded COSS; and (3) decide whether load and demand metrics should reflect historical or future conditions. (Tr. p. 576.12, line 13 – Tr. p. 576.13, line

13) ORS Witness Horii testified that he believes the 1 CP allocation method used in the Duke Companies' COSS in 2018 might have been appropriate two years ago, but that Duke is no longer solely summer peaking and that, by relying on this method, Duke is "underestimating the capacity costs that should be allocated to the NEM solar customers." (Tr. p. 576.19, lines 1 – 13)

In rebuttal, Joint Witness Beach stated that Witness Horii, himself, acknowledged how it is important to have both an embedded and marginal evaluation of cost of service and that embedded COSS is important for "evaluating the policy issue of whether the solar customers would be paying their fair share of costs." (Tr. p. 576-16, lines 16 – 18) Witness Beach stated that these costs are historic costs and that "therefore the allocators used to assign them to customer classes often will consider the demand drivers that caused them to be incurred in the past." (Tr. p. 294.26, lines 9 – 12) Witness Beach concluded that "[f]rom this perspective, Duke's use of the Summer 1 CP allocator is reasonable, as Duke historically has been predominantly a summer-peaking utility, with the winter peaks emerging only in a few recent cold snaps." (Tr. p. 294.26, lines 12 – 15) Witness Beach added that it is more appropriate to address any changes in cost of service methodology in a general rate case, "where a broad range of parties have significant interests in how the utility's costs are allocated to its customer classes." (Tr. p. 294.27, lines1 – 3)

Witness Harris responded to Witness Horii in rebuttal, stating that Witness Horii's citation to testimony from Glen Snider, a witness for the Duke Companies in the avoided cost docket, overlooked that Snider's testimony did not include or relate to an embedded cost study. (Tr. p. 355.6, lines 14 – 17) Witness Harris stated that Witness Horii tends to accept that the methodology was approved in the Duke Companies' last rate case as "just and reasonable" and that it would be inappropriate to consider outside of a base rate case. (Tr. p. 355.6, lines 8 – 13) Witness Harris further testified that he disagreed with ORS Witness Horii that a marginal COSS is more appropriate than an embedded COSS, because it would be insufficient to satisfy the Commission's mandate to consider whether customer-generators are paying for their fair share of historical costs. (Tr. p. 355.8, lines 12 – 19)

Commission Conclusions

The Commission finds that a utility's existing cost of service allocators, modified by the data inputs described in this Order, may be relied upon for purposes of this analytical framework. Cost of service allocations evolve and change from time to time, and if a party seeks to use cost of service allocators differing from those used in the most recent utility rate case, such allocators must be supported by substantial justification.

C. Value of Distributed Energy Resources

(1) Use of existing methodology approved by Order No. 2015-194

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 13 & 14

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett recommended only two changes to the calculation methodology (avoided energy component and line losses component) and did not recommend any additions or deletions to the categories of benefits. (Tr. p. 125.18) Witness Everett stated that the existing valuation methodology is consistent with other "value stack" methodologies, including the one used in New York state. (Tr. p. 125.18, lines 3 – 8)

Witness Everett produced a table populating the valuation categories, leaving five of the categories with a zero value. (Tr. 125.14)

ORS Witness Horii testified that assumptions of a zero avoided transmission and distribution capacity value for NEM should be revised and that a system-average non-zero value should be included in the marginal cost analysis used to inform any new NEM rates. (Tr. p. 576.17, lines 10 – 12)

Joint Witness Beach stated that all of the categories of benefits and costs have been quantified in other similar studies and that there are now well-accepted techniques available for populating those values. (Tr. p. 290.7, lines 3 – 10) Witness Beach stated that the "Commission should establish a reasonable value for the benefit or cost based on an examination of several cases that span a range of reasonable values for such a benefit or cost." *Id.*

Witness Everett, in rebuttal, testified that she did not update the categories where she assigned zero value based on her assertion that "[t]hese values have been thoroughly vetted via the regulatory process in South Carolina, and are the best representation of the value of the current NEM programs." (Tr. p. 131.9, lines 16 – 18)

Witness Beach discussed methods to calculate non-zero values for many of the zero category values determined by DESC witness Everett. (Tr. p. 294.18, line 7)

No other witness recommended the deletion or addition of any of the categories, despite various recommendations to change the calculation methodology for several of the existing valuation categories.

<u>Commission Conclusions</u>

There is no present controversy as to the continuing relevance and value of the valuation categories approved by Order No. 2015-194. Accordingly, the Commission finds that no changes to the value categories are justified at this time. The Commission notes, however, that there are varying levels of consensus and disagreement regarding the appropriate methods to analyze and quantify these value categories. As stated above, the Commission finds that a 20-year time horizon is appropriate for the Act 62 valuation methodology, to match the expected useful life of solar PV. Accordingly, the Commission modifies methodologies for calculating individual categories of value, as discussed below. The Commission expects these methods will continue to evolve over time.

The Commission adopts a standard in this Order that electrical utilities in utilizing the Order No. 2015-194 valuation methodology bear the burden of showing why a zero value is justified and why it is not practical or feasible to provide the analysis required. In some cases, whether a value exists or not is determined by whether an electrical utility is actively taking measures to leverage the characteristics of customer-generators to achieve those values. For example, this is illustrated within the categories of ancillary services and avoided distribution costs. The Commission requires electrical utilities to use best efforts and best practices to populate each category of value in the Order No. 2015-194 methodology, as modified here, in all future proceedings where this analytical framework is utilized.

The application of the Act 236 valuation methodology did not change the underlying policy options available to customer-generators. Rather, it affected only how electrical utilities recover DER program costs. Whatever the relative importance of the methodology in the past, it has relevance to the future course of customer-generator policy. The Commission will revisit these values on a regular basis.

The Commission further finds that, to the extent this Order amends the calculation methodologies for the existing cost-benefit categories approved by Order No. 2015-194, it is appropriate to require that utilities use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code Ann. § 58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery associated with existing customer-generators. S.C. Code Ann. Section 58-40-20€ requires the value of energy produced by customer-generators to be updated annually, and the annual fuel proceedings is the logical proceeding to conduct that update. In addition, pursuant to S.C. Code Ann. Section 58-40-20(E), the NEM methodology must be revisited every five years.

(2) Avoided energy

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 15

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett's direct testimony recommended that the Commission modify the existing NEM Methodology to further segment avoided energy costs to represent variation in avoided energy cost by season and time of day. (Tr. 121, lines 14 – 18). Witness Everett stated that "[f]urther delineating Avoided Energy Costs by season and time of use periods and then applying the actual energy produced during those same designated season and time of day periods would better represent the value of customer-generation." (Tr. p. 125.15, lines 14 – 17)

In his direct testimony, Joint Witness Beach recommended that the costs and benefits of distributed generation, including avoided energy costs, be extended to comply with S.C. Code Ann. §58-40-20(D)(1). (Tr. p. 290.14, lines 14-17; p. 290.15 lines 2-6) He recommended that avoided energy costs be extended to longer terms by using fundamental forecasts of natural gas prices, a driver of marginal energy costs. (Tr. p. 290.21, lines 4 – 8). In his rebuttal testimony, Witness Beach noted that DESC appeared to use Dominion's 10-year levelized energy prices by time-of-use period as included in its standard offer Power Purchase Agreement tariff, and recommended that these avoided energy costs instead be extended to the economic life of a solar system. (Tr. p. 294.5, line 24 – Tr. p. 294.6, line 5) Witness Beach further testified that because gas-fired generation was expected to be the predominant marginal resource on the DESC system in the future, it was reasonable to expect marginal energy costs to increase over time. (Tr. p. 294.6, lines 5 – 7)

Commission Conclusions

This Commission determines each electrical utility's avoided cost every two years in utility-specific avoided cost dockets. Thus, for purposes of utilizing the existing methodology for Act 236 purposes (*i.e.*, for establishing the annual amount of the DER NEM Incentive), the avoided energy costs determined in these proceedings has been sufficient.

With these changes in statute, and in light of the task before us, the Commission modifies the requirement for calculation of avoided energy to include calculation of the seasonal and temporal (*e.g.*, on-peak period value) variations in avoided energy cost. Because the analytical framework is primarily examining the avoided cost value of solar PV, it is appropriate to determine a per kWh average price based on daylight hours where solar is expected to operate.

(3) Avoided capacity

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 16

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In his direct testimony, Joint Witness Beach recommended that the costs and benefits of distributed generation, including avoided capacity costs, be extended to longer terms to comply with S.C. Code Ann. § 58-40-20(D)(1). (Tr. p. 290.14, lines 14 – 17; p. 290.15, lines 2 – 6) Witness Beach testified that these avoided capacity costs could be based on longer-term forecasts available in utility Integrated Resource Plans ("IRPs"), and that it was also important to allocate marginal capacity costs to time periods using long-term metrics for the set of hours when utility loads are likely to peak and generation capacity is most needed. (Tr. p. 290.21, lines 9 – 13)

In his rebuttal testimony, Witness Beach critiqued DESC's stated avoided generation capacity costs for solar PV projects. Specifically, Witness Beach estimated solar's capacity contribution by reviewing DESC's hourly loads from 2014 to 2019 and developed a Peak Capacity Allocation Factor ("PCAF") for each hour of the year, based on the extent to which hourly load exceeded 90% of the annual peak hour's load. (Tr. p. 294.8, lines 15 – 20) Witness Beach then applied a solar profile to this PCAF distribution and determined that the solar PV capacity contribution was 34%, rather than the 11% solar capacity contribution adopted in Order No. 2019-847. (Tr. p. 294.9, lines 4-7; Tr. p. 294.10, lines 12 – 14)

Commission Conclusions

The Commission modifies the existing valuation methodology to require that capacity costs be based on a 20-year forecast conducted in a similar fashion as the forecast used for the IRP process. The Commission also adopts Witness Beach's recommendation that forecasts of capacity costs take into consideration the hours in which utility loads are likely to peak and when generation is most needed.

(4) Ancillary services

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 17

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett described ancillary services as a generation-related cost "related to maintaining system reliability and voltage control." (Tr. p. 125.6, lines 1 – 2) Based on Order No. 2020-244 from DESC's 2019 avoided cost proceeding, Witness Everett assigned a zero value to ancillary services. (Tr. p. 125.14)

ORS Witness Horii noted in his testimony that ancillary services were assigned a zero value, stating that "some placeholder values may represent directly monetized costs or benefits (*e.g.*, ancillary services) that may currently be small and/or difficult to quantify." (Hr'g Ex. 15 at 81) Witness Horii also provided that neither Maryland nor Montana quantified the value of ancillary services due to the "complexity of calculations and difficulty in deriving accurate results" and because ancillary services were "considered to be subjective and not quantifiable," respectively. (Hr'g Ex. 15 at 55)

Witness Beach did not attempt to quantify the value of ancillary services, but did note that he believes all of the NEM methodology components could be quantified; he further testified that "[i]f there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category, but to examine several cases that span a range of reasonable values for this benefit or cost and use that review to establish a reasonable value." (Tr. p. 290.20, lines 7 – 14) Alder Energy Witness Zimmerman agreed with Witness Beach's testimony on this issue, recommending that the Commission affirmatively value ancillary services to achieve an accurate value of customer-generated solar. (Tr. p. 494.7, lines 14 – 17)

Commission Conclusions

The Commission finds that no change is required to the current methodology, as the record bears out that quantifying ancillary services is challenging and there are not current opportunities for customer-generators to provide such services. With the expectation that technology will continue to evolve rapidly and that customer utilization of battery storage will increase the types of services that customer-generators paired with storage can provide, the Commission requires the electrical utilities to investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices (*e.g.*, IEEE standards for DER and distributed generation).

(5) Avoided Carbon Dioxide and Environmental Compliance Costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 18

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

Joint Witness Beach testified that the value of avoided carbon emissions, as included in the value stack of benefits adopted in Order No. 2015-194, should not be assigned a zero value. (Tr. p. 290.20, lines 14 – 20).

However, DESC Witness Everett gave testimony supporting the previously established factor included as No. 7 in the current NEM DER valuation schedule, which is entitled "Environmental Costs" and is defined as "Increase/reduction of environmental compliance and/or system costs to the Utility." (Tr. p. 125.12) This element or factor is calculated using the following methodology:

> The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/or Utility system costs must be quantifiable and not based on estimates.

(Tr. p. 125.12).

Commission Conclusions

The Commission finds that it is reasonable to retain the existing method of calculation for costs and benefits related to carbon dioxide and other environmental compliance. If state or federal laws impose regulatory burdens on electric utilities going forward, then electric utilities shall provide the Commission with the quantifiable costs of complying with those regulations that limit carbon dioxide and methane emissions so that customer-generators can be credited with an appropriate benefit in meeting those emission standards.

(6) Avoided fuel hedge

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 19

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In his rebuttal testimony, Joint Witness Beach noted that DESC Witness Everett did not discuss or include a fuel hedge benefit in her testimony, and argued that such a benefit should be included. Witness Beach testified that because renewable generation reduces a utility's use of natural gas, it decreases the exposure of ratepayers to volatility in natural gas prices. (Tr. p. 294.15, lines 6 – 10)

Alder Energy Witness Zimmerman agreed with Witness Beach's testimony on this issue, recommending that the Commission affirmatively value all methodology components, including fuel hedge, to achieve an accurate value of customer-generated solar. (Tr. p. 494.7, lines 14 – 17)

Commission Conclusions

The Commission concludes that if the electrical utility engaged in financial hedging activities to hedge against rising fuel costs, then the electric utility shall keep sufficient data to determine the prudency of those costs.

(7) Avoided transmission and distribution costs

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 20

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett defined distribution and transmission related costs as the "costs of building transmission and distribution capacity… and… cost related to line losses resulting from moving electricity across the system from generation to the customer." (Tr. p. 125.6, lines 7 – 12) Witness Everett stated in rebuttal that she did not attempt to update the zero value for avoided T&D in her analysis in direct because "[t]hese values have been thoroughly vetted via the regulatory process in South Carolina, and are the best representation of the value of the current NEM programs." (Tr. p. 131.9, lines 13 – 18)

Joint Witness Beach stated in direct testimony that "[a] fundamental attribute of DERs is that they are installed on the customer's premises, behind the meter and interconnected to the utility distribution system" and that "at today's penetrations of DERs, the predominant impact of DER generation is to reduce the peak demand for electricity that must be served from the transmission and distribution system." (Tr. p. 290.21, lines 20 – 23) Witness Beach further testified that it is standard for utilities to value avoided transmission and distribution ("T&D") values for other similar demand-side programs, including DEC and DEP. (Tr. p. 290.14, line 1) In terms of the method of calculating avoided T&D values, Witness Beach testified:

> There are longstanding and well-accepted methods to calculate long-run marginal costs for transmission and distribution capacity. Many utilities use the well-established National Economic Research Associates (NERA) regression method to determine their long-run marginal distribution capacity costs that vary with changes in load. The NERA regression model fits incremental transmission and distribution investment costs to peak load growth using at least 15 years of data to capture the utility's long-term marginal costs for capacity. The slope of the resulting regression line provides an estimate of the marginal cost of transmission or distribution investments

> associated with changes in peak demand.
> (Tr. p. 290.22, lines 1 – 10)

ORS Witness Horii testified that it is clearly possible to calculate distribution marginal capacity costs and that there are a "myriad" of jurisdictions that currently do so. (Tr. p. 576.24, lines 9 – 13) Witness Horii cited a 2014 benchmarking study used in Colorado that included survey of avoided T&D costs for 20 states or regions. *Id.* Witness Horii stated that examples like this counter "the assertion that meaningful, aggregated distribution avoided costs cannot be calculated for DSM programs." (Tr. p. 576.27, lines 1 –7) Witness Horii provided that "assumptions of zero ($0) T&D capacity value for NEM solar should be revised and a system average non-zero value be included in the marginal costs analysis used to inform any new NEM rates." (Tr. p. 576.17, lines 10 – 12)

For calculating avoided T&D values, Witness Horii testified that it would be ideal to estimate highly locational marginal distribution values for each smaller portion of the distribution system that has a capacity need in the near term. (Tr. p. 576.24, lines 16 – 18) Short of this ideal situation—instead of assuming there is no avoided T&D value anywhere on the system—Witness Horii testified that "[i]t would be more appropriate to use a system average distribution capacity value than to exclude distribution capacity completely." (Tr. p. 576.25, lines 1 – 3) Witness Horii stated that the approach to calculating avoided distribution also applies to calculating avoided transmission. (Tr. p. 576.27, lines 8 – 16)

Witness Horii further explained how more precise avoided T&D values can be derived, but those approaches tend to have data that is not commonly available, including load forecasts for each distribution feeder and considerations of the amount of demand-side resources on a feeder. (Tr. p. 576.25, line 20 – p. 576.26, line 17). Even without such sophisticated procedures and granular data, Witness Horii stated that "distribution avoided costs are more commonly calculated using far less data, and both DESC and Duke have provided estimates of T&D marginal capacity costs" in response to Vote Solar data requests. *Id.*

Commission Conclusions

The Commission finds that avoided transmission and distribution may have a non-zero value and electrical utilities should make greater effort to quantify a value using a methodology that accounts for relative availability of and granularity of data about the distribution and transmission system. While transmission and distribution costs are location specific, the Commission acknowledges that it would take some analytical sophistication and a more transparent T&D planning process to assign values with that level of precision and granularity in time and location. Accordingly, it is reasonable to provide electrical utilities flexibility at this time to employ a methodology that reflects the current state of available data.

Electrical utilities, however, are directed to provide the Commission, within 90 days of this order, a narrative of how they plan to improve these data capabilities over time to improve the insight into the transmission and distribution systems and to modernize the planning of transmission and distribution assets to take into account the ability of DERs to avoid or defer traditional, utility-owned T&D capital investments.

(8) Avoided line losses

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 21

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett recommended modifying the avoided energy losses/line losses component of the NEM methodology. (Tr. p. 125.16, lines 20 – 23) Specifically, Witness Everett testified that her recommendation was to first distinguish transmission and distribution losses, and then create a value for transmission losses that would apply to all customer-generation and a distribution losses component that applies to only the customer-generation simultaneously consumed on site. *Id.* According to Witness Everett, while kWhs consumed on site avoid both transmission and distribution losses, kWhs exported onto the system may not necessarily reduce the losses of energy delivered to other customer meters. (Tr. p. 125.17, lines 1 – 9) She further testified that because exported kWh must be transported across the distribution system, the value of that kWh could also be eroded by distribution losses, thus becoming a negative value. (Tr. p. 125.17, lines 6 – 9)

Joint Witness Beach's rebuttal testimony disagreed that power exported from distributed solar facilities does not avoid distribution line losses. (Tr. pp. 294.10 – 294.11) Witness Beach testified that "[a]ssuming that the penetration of distributed solar is low, as it is in South Carolina today, the power exported from a small customer-owned solar system on the distribution system will be consumed by the solar customer's immediate neighbors," (Tr. p. 294.11, lines 1 – 4) and that "because the exports from distributed solar move such a short distance over the distribution system before they are consumed by the neighbors, the avoided line losses will not be significantly different thanthe avoided line losses from power consumed behind the meter." (Tr. p. 294.11, lines 12 – 15) Witness Beach testified that a solar PV project located behind a customer's meter would avoid marginal line losses on both the DESC transmission and distribution system for its entire output, and calculated those total avoided losses to be $.00493/kWh on the DESC system. (Tr. p. 294.11, lines 19 – 21)

DEC/DEP Witness Harris testified that Duke did not consider line losses in its analysis of how energy exports from NEM customers reduce system generation costs "because such losses are typically *de minimis*." (Tr. p. 353.9, lines 2 – 3)

Commission Conclusions

The Commission modifies the existing methodology to require that electrical utilities determine the marginal line losses associated with customer-generator facilities. If marginal line loss data does not exist for an electrical utility, the Commission directs the development of a plan within 90-days of this Order to acquire this capability.

(9) *Utility integration, interconnection, and administrative costs*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 22 AND 23

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

In direct testimony, DESC Witness Everett stated that "[i]nterconnection costs include those related to connecting a customer's facility or home to the grid not covered in specific Interconnection Fees. Integration costs are those related to maintaining voltage levels and load following given variability in the customer's loads and customer-generation resource production." (Tr. p. 125.6, lines 14 – 18) Witness Everett further stated that "[a]dministrative costs include any additional costs the utility incurs to provide a NEM tariff, which may include the costs related to billing practices or incremental customer call center support." (Tr. p. 125.7, lines 1 – 3) Witness Everett identified a zero value for administrative costs in her table of values. (Tr. p. 125.14, line 1)

Commission Conclusions

While integration costs for solar generation are currently determined in avoided cost proceedings, the Commission finds here that it is inappropriate to apply this category to customer-generation that is completely consumed behind-the-meter. As discussed by Witnesses Beach and Harris, behind-the-meter consumption is equivalent to energy efficiency and any changes in load associated with offsetting purchases from the grid at any given time by any given customer will be smoothed by geographic and class diversity. (Tr. p. 38 – Tr. p. 41)

Moreover, the Commission now requires electrical utilities to begin to track incremental interconnection costs to ensure that the currently approved interconnection fee covers the reasonable costs of facilitating initial interconnection to the grid of customer-generator facilities. Similarly, if an electrical utility wishes to assign a value to administrative costs, it is necessary that the utility track and record incremental costs of administrating the NEM program that are distinguished from administrative costs that would have otherwise applied if the customer were not a customer-generator.

D. Economic Impacts of Net Energy Metering Program

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 24 THROUGH 26

Summary of the Evidence

The evidence in support of these findings of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

As a threshold issue, the plain language of Act 62 – specifically S.C. Code Ann. Section 58-40-20 (D)(4) requires the Commission to consider "the direct and indirect economic impact of the net energy metering program to the State."

SACE, CCL, Upstate Forever, and Vote Solar Witness Hefner testified that there are substantial economic impacts in South Carolina attributable to rooftop solar. (Tr. p. 415, line 18 – Tr. p. 416, line 8; Tr. p. 417.6, line 14 – Tr. p. 417.7, line 25) Witness Hefner explained that economic impact includes direct, indirect, and induced impacts. (Tr. p. 417.5, lines 3 – 12) Direct benefits are the purchases of local goods, services, and labor. *Id.* Indirect impacts include wages paid to the installers of solar, and induced impacts include purchases of goods and services with those wages. *Id.* In the context of the rooftop solar sector of the solar industry, direct impacts include wages paid to the installers of solar panels, indirect impacts include the purchase of goods and services by businesses that install solar panels in South Carolina, and induced impacts are the impact of purchases as a result of wages paid to those businesses. *Id.*

DESC Witness Furtick objected to the Commission considering the economic benefits associated with induced impacts, arguing that these impacts are "almost impossible to accurately quantify." (Tr. p. 25.2, lines 9 – 11) Witness Furtick conceded that the number of solar jobs created in South Carolina and the wages paid to workers employed in those jobs are measures of economic impact on the State's economy. (Tr. p.50, lines 11 – 25)

ORS Witness Horii acknowledged that residential solar generation provides myriad social and market benefits including CO2 value, healthcare and mortality impacts from criteria pollutant reductions, market price impacts, and increased jobs. (Tr. p. 576.5, lines 16 – 19)

DEC/DEP Witness Dr. Wright proposes a number of considerations and guidelines that should be included when developing an appropriate economic impact analysis:

- Properly characterizing the purpose of the economic study and reporting the results with appropriate recognition of this purpose.
- Considering the economic consequences if a policy is not adopted, referred to as the "but for" option.
- Ensuring an "apples to apples" comparison.
- Properly considering incentives and subsidies.
- Considering electric rate impacts.
- Properly accounting for the timing of the economic stimulus and related impacts.
- Appropriately characterizing the presumed economic impacts.
- Utilizing an appropriate geographic region.
- Recognizing sound economic principles in the overall results.

(Tr. p. 260.11 – p. 260.12)

Dr. Wright addresses two models – the IMPLAN and JEDI models – stating that "using these models for an NEM economic analysis should incorporate an alternative investment analysis, possibly one that is a substitute energy supply, either of which will be a reduction in benefits, from the gross NEM alternative." (Tr. p. 269.18, lines 9 – 12)

Commission Conclusions

With regard to the direct and indirect economic impacts that benefit the utility service area in South Carolina, the Commission concludes that, while it must consider these aspects pursuant to Act 62, it is currently unable to adequately quantify the direct economic benefits from the record currently before us. However, the Commission recognizes there are certain indirect benefits like job creation, infrastructure investments, and growth in the state's economy that do exist but are difficult to quantify given the existing record. Going forward the Commission adopts witness Dr. Wright's analysis of direct and indirect beneficial economic impacts for future NEM proceedings.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 27

Summary of the Evidence

The evidence in support of this finding of fact are found in the testimony and exhibits in this Docket and the entire record in this proceeding.

DESC Witness Everett testified that the methodology employed by DESC to conduct a cost-benefit analysis is based on the "California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects," which is widely used to evaluate customer programs. (Tr. p. 125.21, lines 9-14). According to Witness Everett, DESC used four of the standard tests from the manual, specifically, the "Total Resource Cost Test;" "Program Administrator Cost Test;" "Participant Cost Test;" and "Ratepayer Impact Measure Test." (Tr. p. 125.23, line 4 (Table 4)). Witness Everett explains that these tests are appropriate to evaluate NEM programs because, "The tests outlined in the Standard Practice Manual are widely used in evaluation of other customer programs such as Energy Efficiency and Demand Response, which have similar characteristics to NEM programs, particularly since customers install behind the meter technologies to reduce their energy bills." (Tr. p. 125.23, lines 9-12)

Witness Beach illustrates the different approaches that each cost-benefit test incorporates, including the incorporation of different attributes of demand-side benefit and cost. (Tr. p. 290.17, line 5 (Table 1)). Witness Beach advocates for the Commission to give priority to the Utility Cost Test over the Ratepayer Impact Measure test by explaining the differences and why, in his opinion, one test should be used instead of the other. (Tr. pp. 290.17 – 290.20)

Commission Conclusions

The Commission concludes that the disagreement as to which cost-benefit tests or methods should be used in this proceeding illustrates the importance of receiving all relevant information into evidence of record, then using the Commission's judgment and discretion to properly assign weight to the evidence presented. Consistent with the desire to fully receive relevant information, the Commission finds that all the cost-benefit tests presented in this case illustrate different, relevant perspectives and information. Therefore, in this and future proceedings, the use of a variety of relevant cost-benefit tests may be considered and appropriately weighed by the Commission in its discretion.

VI. ORDERING PARAGRAPHS

1. The Commission requires that utilities begin to incorporate the analytical needs of Act 62 in designing load research studies ordinarily used to inform cost of service studies and to initiate a load research study that includes a statistically significant sample of customer-generators.

2. The Commission requires that in proceedings in which cost of service implications are raised regarding NEM customers, both embedded and marginal costs must be fully evaluated, including long-term cost implications, with the NEM customers being considered – for these analytical purposes only – as a separate rate class.

3. The Commission declines, at this time, to delineate NEM customer-generators into a separate rate class.

4. In this and future proceedings, for the purposes of cost-benefit analysis and

avoided capacity calculation for DER, solar PV shall be considered with a 20-year lifespan.

5. In this and future proceedings, behind-the-meter generation used by customer-generators shall be treated as energy efficiency or demand-side management resources.

6. In this and future proceedings, NEM customer-generators that are net exporters of power during an hour should be recorded as having zero, not negative, energy consumption during that time.

7. In this and future proceedings, the use of cost of service allocators previously approved by the Commission in the most recent rate case are acceptable. Cost of service allocators differing from those previously approved by the Commission may be used with substantial justification.

8. With regard to the value of distributed energy generation under Act 62methodology approved in Commission Order No. 2015-194, the value stack shall be retained with the following modifications:

A. That the stack shall reflect a 20-year expected useful life of solar PV generation assets.

B. That avoided line losses be calculated on a marginal basis considering daylight hours only.

C. That utility integration costs (which are determined in the avoided costs proceeding) should only be applied to exported power because behind the meter consumption is to be viewed the same as energy efficiency and that integrated costs for customer-sited DER should focus more on distribution system related impacts. Electrical utilities shall track incremental interconnection costs associated with customer-generated interconnections not covered by an interconnection application fee.

D. Customer generators are not currently utilized to provide ancillary services. Therefore, electric utilities are hereby required to evaluate the creation of programs to leverage DER to provide ancillary services especially as technology development leads to storage.

E. Inclusion of a methodology to quantify long-run impacts of aggregate customer generators on avoided transmission and distribution costs. Thus, the electrical utilities shall collect data with sufficient granularity to provide the Commission with quantitative analysis of avoided transmission and distribution costs.

F. If the electrical utility engaged in financial hedging activities to hedge against rising fuel costs, then the electric utility shall keep sufficient data to determine the prudency of those costs.

G. If state or federal laws impose regulatory burdens on electric utilities going forward, then electric utilities shall provide the Commission with the quantifiable costs of complying with those regulations that limit carbon dioxide and methane emissions so that customer generators can be credited with an appropriate benefit in meeting those emission standards.

H. With regard to the direct and indirect economic impacts that benefit the utility service area in South Carolina, the Commission adopts witness Dr. Wright's analysis of direct and indirect beneficial economic impacts for future NEM proceedings.

9. To the extent the existing DER valuation methodology adopted by Order No. 2015-294 is modified by this Order, the Commission directs utilities to use these updated methodologies in determining the distributed energy component of their overall fuel factor in annual fuel proceedings under S.C. Code Ann. § 58-27-865(A) for purposes of determining the NEM DER Incentive cost recovery associated with existing customer-generators.

10. This Order will remain in full force and effect until further order of the Commission.

BY ORDER OF THE COMMISSION:

Florence P. Belser, Vice Chair
Public Service Commission of
South Carolina

III. DISCUSSION OF THE HEARING

The Commission conducted a generic proceeding on this matter on February 3, 2015, in the hearing room of the Commission with the Honorable Nikiya "Nikki" Hall presiding. At the outset of the hearing, ORS counsel described the Settlement Agreement. The methodology proposed in the Settlement Agreement ("Methodology") is as follows:

Net Energy Metering ("NEM") Methodology

+/- Avoided Energy
+/- Energy Losses/Line Losses
+/- Avoided Capacity
+/- Ancillary Services
+/- Transmission and Distribution ("T&D") Capacity
+/- Avoided Criteria Pollutants
+/- Avoided CO_2 Emission Cost
+/- Fuel Hedge
+/- Utility Integration & Interconnection Costs
+/- Utility Administration Costs
+/- Environmental Costs
= **Total Value of NEM Distributed Energy Resource**

The following table details the components of the Methodology.

Methodology Component	Description	Calculation Methodology/Value
+/- Avoided Energy	Increase/reduction in variable costs to the Utility from conventional energy sources, i.e. fuel use and power plant operations, associated with the adoption of NEM.	Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning ("IRP") study and/or Public Utility Regulatory Policy Act ("PURPA") Avoided Cost formulation.
+/- Energy Losses/Line Losses	Increase/reduction of electricity losses by the Utility from the points of generation to the points of delivery associated with the adoption of NEM.	Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when available.
+/- Avoided Capacity	Increase/reduction in the fixed costs to the Utility of building and maintaining new conventional generation resources associated with the adoption of NEM.	Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs should be adjusted for the appropriate energy losses.

Methodology Component	Description	Calculation Methodology/Value
+/- Ancillary Services	Increase/reduction of the costs of services for the Utility such as operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of NEM.	Component includes the increase/decrease in the cost of each Utility's providing or procurement of services, whether services are based on variable load requirements and/or based on a fixed/static requirement, i.e. determined by an N-1 contingency. It also includes the cost of future NEM technologies like "smart inverters" if such technologies can provide services like VAR support, etc.
+/- T&D Capacity	Increase/reduction of costs to the Utility associated with expanding, replacing and/or upgrading transmission and/or distribution capacity associated with the adoption of NEM.	Marginal T&D distribution costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of NEM generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the NEM generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses.
+/- Avoided Criteria Pollutants	Increase/reduction of SOx, NOx, and PM10 emission costs to the Utility due to increase/reduction in production from the Utility's marginal generating resources associated with the adoption of NEM generation if not already included in the Avoided Energy component.	The costs of these criteria pollutants are most likely already accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately. The Avoided Energy component must specify if these are included.
+/- Avoided CO_2 Emissions Cost	Increase/reduction of CO_2 emissions due to increase/reduction in production from each Utility's marginal generating resources associated with the adoption of NEM generation.	The cost of CO_2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions.
+/- Fuel Hedge	Increase/reduction in administrative costs to the Utility of locking in future price of fuel associated with the adoption of NEM.	Component includes the increases/decreases in administrative costs of any Utility's current fuel hedging program as a result of NEM adoption and the cost or benefit associated with serving a portion of its load with a resource that has less volatility due to fuel costs than certain fossil fuels. This value does not include commodity gains or losses and may currently be zero.
+/- Utility Integration & Interconnection Costs	Increase/reduction of costs borne by each Utility to interconnect and integrate NEM.	Costs can be determined most easily by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of NEM. Appropriate levels of photovoltaic penetration increases in South Carolina should be included.

Methodology Component	Description	Calculation Methodology/Value
+/- Utility Administration Costs	Increase/reduction of costs borne by each Utility to administer NEM.	Component includes the incremental costs associated with net metering, such as hand billing of net metering customers and other administrative costs.
+/- Environmental Costs	Increase/reduction of environmental compliance and/or system costs to the Utility.	The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/ or Utility system costs must be quantifiable and not based on estimates.

The Settlement Agreement was accepted into the record as Hearing Exhibit 1. Prior to the hearing and without objection from the remaining parties, the Commission granted SCE&G, Duke, SBA and ORS permission to utilize panels for the presentation of witnesses.

SCE&G presented W. Keller Kissam as its first witness. Witness Kissam provided information confirming SCE&G's commitment to promoting distributed renewable generation in South Carolina and supporting the Commission's adoption of the Settlement Agreement. Witness Kissam discussed SCE&G's current solar resources, which include a partnership with Boeing that resulted in installation of 2.6 megawatts of solar laminate on top of their aircraft manufacturing facility, and other planned projects. Additionally, witness Kissam testified that planned projects add up to fifty (50) megawatts of utility-scale solar to its system. Regarding the Act, witness Kissam briefly discussed its three primary aspects: net energy metering ("NEM"), distributed energy resource ("DER") program, and solar leasing.